

NATURAL GAS

Production

Indonesia has natural gas reserves of 187.09 trillion standard cubic feet (TSCF) as of 2006 (93.95 TSCF proven and 93.14 TSCF possible), a decline of 3% from 2005. In 2006, the country produced 2.954 TSCF of gas, ranking eighth in world gas production. Production declined one percent from 2005 levels.

Indonesia's largest producers in 2006 (in order) were Total, Pertamina, ConocoPhillips, ExxonMobil, VICO, BP, Petrochina, and Chevron, all of which operate under production sharing contracts and account for 90 percent of the country's total production.

Gas reserves are equivalent to almost four times Indonesia's oil reserves and can supply the country for 62 years at current production rates. According to the GOI, over 71 percent of natural gas reserves are located offshore, with the largest reserves found off Natuna Island (28.8%), East Kalimantan (25.2%), South Sumatra (13%) and Papua (12.8%). However, not all of these reserves are commercially viable, due to both the quality of the gas and the distance to market.

In 2006, the government announced a policy re-orienting natural gas production to serve the domestic electric power market. Government ministers said Indonesia will honor all existing contracts but not necessarily renew current ones as they expire between 2008 and 2011.

In 2006, Indonesia supplied 14% of the world's LNG, down from 26% in 2003. LNG accounts for 41% of the country's total natural gas production and is

exported mainly to Japan, South Korea and Taiwan. Pipeline gas exports to Singapore began in 2001, reaching 181.3 BSCF in 2005 (the latest year for which figures are available). A new Sumatra-Singapore pipeline was inaugurated in late 2003. Revenues from gas exports are substantial -- \$10.5 billion in 2006, about 10 percent of Indonesia's total export revenues.

Most of Indonesia's gas comes from Natuna (53.56 TSCF in reserves), Kalimantan (47.77 TSCF in reserves) and Sumatra (33.51 TSCF in reserves), but there are large reserves in Papua (24.47 TSCF in reserves) and other areas in the archipelago (27.78 TSCF in reserves).

Gross Natural Gas Production by Major Producers (MMSCF)

Company	2004	2005	2006	%
Total	909,932	1,067,190	1,097,341	2.83
Pertamina	383,870	379,612	368,576	-2.91
ExxonMobil	507,096	379,125	322,254	-15.00
ConocoPhillips	319,317	344,886	345,070	0.05
Vico	329,511	251,876	208,371	-17.27
BP	182,209	123,668	136,799	10.62
Chevron (Unocal)	124,199	120,343	107,225	-10.90
Petrochina/Devon Energy	73,668	67,629	111,090	64.26
Others	200,330	251,012	257,372	2.53
Total	3,030,132	2,985,341	2,954,098	-1.05

Source: MIGAS

Roughly 55% of Indonesia's natural gas was marketed as LNG or liquefied petroleum gas (LPG) for export, 5.6% for electricity, 6.4% for fertilizer and 3.4% for city gas. Less than 6% was flared.

Indonesia lost its title to Qatar as the world's leading exporter of LNG in 2006, according to media reports and industry analysts. Its share of world production

dropped from 18.8% in 2005 to 14% in 2006. Indonesia exported 46.1 million tons of LNG in 2006, according to government data. LNG production at Arun and Badak (Bontang) was 22.4 million metric tons (MT) in 2006, a decrease from the 2005 production level of 23.7 million MT. Japan, South Korea and Taiwan were the key markets for LNG.

Indonesia began exporting 325 million cubic feet per day (mmcf) to Singapore via a subsea pipeline from West Natuna under a 22-year contract in 2001.

Deliveries of natural gas to Malaysia's Duyong gas platform began in August 2002, under a 20-year contract for 250 mmcf. Gas sale revenues will likely total \$14.2 billion over the life of both contracts. In August 2003, the South Sumatra-Singapore gas pipeline was completed. It will eventually supply 350 mmcf over a 20-year contract.

Lower Subsidies, New Laws Stimulate Domestic Demand

Domestically, gas demand comes primarily from fertilizer and petrochemical plants (34%) and the power industry (25%). The GOI has indicated that gas will play a significant role in meeting the country's growing electric power demands. The reduction of fuel subsidies in October 2005, and their elimination for some industrial uses, eased fuel price distortions and made natural gas increasingly competitive as a fuel alternative, stimulating gas demand. The government eliminated the subsidy for industry fuels in 2005 and phased out premium fuel and gasoil subsidies by the end of 2006. In October 2005, state gas company PGN raised industrial gas prices to \$4.5 per mmbtu from \$3.9 per mmbtu.

In January 2006 PGN raised prices again to \$5 per mmbtu, and again in 2008 to \$5.60 per mmbtu. Even at that price, however, gas was still equivalent to only about 19 cents per liter of diesel oil compared to the industrial diesel oil price of \$1.20 per liter or the subsidized auto diesel price of 60 cents per liter. In May 2008, PGN agreed to increase its gas sales to PLN by 200 million cubic feet per day under a three year contract at a price of \$5.60 per mmbtu. Gas will be transmitted from PGN South Sumatra to West Java via pipeline.

The Oil and Gas Law of 2001 introduced other changes that encourage domestic gas use. The new law permits direct "free market" negotiations of gas contracts between buyer and seller. Previously, production sharing contractors (PSCs) had to sell their gas to the state-owned petroleum company, Pertamina, which in turn sold the gas to the final buyer. Several PSCs report that the GOI's new direct negotiation mechanism is working well and that the upstream authority BP Migas has generally stayed out of the negotiations, except in cases where either the buyer or seller requested its participation. However, MIGAS recently came out against an expansion of the program.

These provisions have raised domestic demand estimates and led to a number of new gas sales agreements. BP Migas estimates that by 2018, Indonesia's domestic gas demand will increase to 2.18 TSCF per year. In 2006, domestic gas demand was 1.35 TSCF with 4% growth projected in 2007. Meanwhile, domestic gas sales reached 0.92 TSCF in 2007, a slight increase from 0.85 TSCF in 2006.

Growing Power Needs Will Drive Gas Demand

Power generation needs in Java and Bali will also drive growing domestic gas demand. Over the last several years, peak power demand grew by an average of six percent annually, while power capacity did not increase. Peak loads on the Java-Bali grid (which accounts for of 80 percent of Indonesia's power demand) reached a record high of 16,251 MW in November 2007, and were projected by PLN to reach 16,995 MW in 2008. As a result, PLN acknowledged that their reserve margin declined from 28% in 2003 to 21% in 2008, and are projected to decline to 14% in 2009. (Note: desired reserve margins are normally between 25 and 30 percent. PLN's numbers are based on declared capacity, rather than reliable capacity. Maintenance on plants can bring down actual capacity and reserve margins.)

PLN estimates that Indonesia needs over 23,000 MW in new capacity between 2005 and 2015 to prevent a long-term power crisis and restore its power reserve margin. Much of that new capacity will be fueled by gas and coal. PLN plans to raise natural gas use by the power sector from 17% in 2004 to 40% by 2015. By volume, this means an increase from 483 mmcf to 1.7 billion cubic feet per day (bcfd) in 2015.

Increasing gas consumption in the energy mix makes strong economic sense, particularly with current crude oil price levels. Petroleum-based fuels are expensive – about 6.2 cents per kilowatt hour (kWh), or 2.5 times more costly than gas. PLN spends about \$1.6 billion annually on oil-based fuels and estimates it can save up to \$1 billion per year by

switching to gas. This, however, requires a reliable gas infrastructure and a secure gas supply. The switch is an important element in restoring the financial health of Indonesia's power industry, although low electricity tariffs continue to undermine the industry. At the same time, it also has significant implications for Indonesia's export revenues derived from natural gas.

Impediments to Domestic Gas Growth

In its Energy Blueprint, the Ministry of Energy and Mineral Resources plans to increase gas's proportion in the national energy mix to 30.6% by 2025 from the current 26.5%. However despite changes spurring gas demand, impediments limit domestic gas growth. The primary obstacles include a limited transmission and distribution system, financing limitations, and continued regulatory uncertainty. To address the inadequate state of gas transmission and distribution networks, state gas utility PGN started four new transmission projects to meet rising power sector demands for gas, as follows:

Projects	Length (km)	Capacity (mmscfd)	Completion
Grissik – W.Java	661	400	2007
Duri – Medan	521	250	2007
E. Kalimantan - Central Java	1,219	1,100	2007/2010
E.Java-W.Java	680	350	2008/2010

Source: PGN

In addition to these projects, the GOI is proposing to build an LNG receiving terminal in West Java, to process and distribute gas from existing LNG plants (Bontang), as well as future plants in Papua (Tangguh) and South Sulawesi (Donggi). PGN is extending its distribution network and plans to ship compressed natural gas (CNG) over short

to medium distances to remote areas. In addition, PGN is also investigating the feasibility of developing an integrated mini-LNG transportation system. The project will involve a mini-LNG receiving terminal located in Makassar, South Sulawesi, which will ship LNG from the Bontang LNG plant.

Many producers require explicit financial guarantees to sell gas domestically. The government's reluctance to provide such guarantees poses another obstacle to domestic gas growth, according to industry observers. In the power industry, a number of PSCs have requested that PLN provide standby letters of credit (SBLC) before investing in long-term gas supply agreements. According to industry analysts, PLN's credit availability with government-linked banks is limited. PLN has asked Bank Indonesia to exclude SBLCs from the legal lending limit to get around this obstacle. Some power analysts suggest that if PLN would permit higher returns on investment, companies would be willing to assume more of this risk themselves.

Another constraint to gas development is the absence of a competitive gas pricing system. Under the historic system, prices for gas supply contracts are negotiated on a field-by-field basis between Pertamina and individual producers after the discovery of the gas field. Prices are fixed for a designated supply for the duration of the contract. Hence, the producer's price for gas is different for each PSC. Consumer prices are set on a cost-plus basis.

Currently, the negotiated gas price for power generation is far below the global average, in the range of \$4.50 to \$6 per mmbtu, compared to current global

natural gas prices, which average around \$11 per mmbtu in mid-2008. The World Bank and the Asian Development Bank (ADB) have urged Indonesia to adopt a pricing regime that creates greater incentives for companies to find and produce gas. A competitive domestic gas price would allow Indonesia to realize the full value and potential of its gas reserves. Without pricing changes, the domestic gas market provides few incentives for the exploration and development of gas fields that are too small to support LNG but more than adequate for domestic gas customers. A second major constraint is the absence of a predictable basis for forecasting the future value of gas, such as an indexed price formula. A final constraint has been the subsidy provided for alternative fuels.

Regulations Require Clarification

The current regulatory environment sends mixed signals to investors which inhibits the exploration and development of potential gas reserves. Despite domestic market obligation (DMO) provisions in the 2001 Oil and Gas law promoting gas use and the issuance of downstream Regulation 36, industry players still do not see a clear set of "rules of the game." Industry players say that they want clarification of the exact DMO quantity and whether the government will honor existing PSC contracts. In addition, doubts about contract sanctity, contract extensions, security, and taxation hurt the gas investment climate.

The end result of this uncertainty, and the consequent lack of exploration, is stark. According to the American Chamber of Commerce, gas blocks signed before 1971 still account for nearly 60 percent of Indonesia's commercial reserves. Blocks

signed after 1990 account for only 14 percent of commercial reserves.

Expanding Future Production

Indonesia is blessed with abundant reserves, although there is a geographical mismatch between location of gas reserves and energy needs. The Ministry of Energy and Mineral Resources estimates total gas demand between 2008-2018 will reach 22,200 BSCF, while supply is estimated at 13,231 BSCF. In the long-term, Java's additional gas supply will rely on the development of gas fields outside the island and the completion of pipeline and LNG projects.

In addition to geographical constraints, other barriers to developing Indonesia's gas resources include the availability of financing, long project lead-time, and the lack of incentives to explore and exploit gas reserves.

Private sector participants identified the following key areas to increase development in the gas sector:

- Increase incentives to find and produce natural gas;
- Harmonize conflicting laws and eliminate the lengthy bureaucratic process for project approval;
- Clarify the gas DMO obligation;
- Promote private investment and ownership, through price stability and an equitable cost recovery mechanism;
- Address gas reliability concerns for those firms that invest in major gas facilities; and
- Provide government guarantees for gas payment by state owned enterprises.

A Trans-ASEAN Gas Pipeline?

ASEAN's Energy ministers signed a memorandum of understanding on July 5, 2002 to push ahead with a \$7 billion natural gas pipeline project in a bid to alleviate concerns over supply shortages and to improve economic development. Minister of Energy and Mineral Resources Purnomo Yusgiantoro said the project's masterplan has been completed, and a council will soon be established to oversee the completion of the gas grid. Purnomo said more than 1,000 kilometers of the grid have already been constructed. ASEAN has identified the need for 4,500 kilometers of pipeline to complete the project, which might reach 6,000 kilometers, if the necessary new Indonesian domestic pipelines are included.

Purnomo said Indonesia will be a major player in the trans-ASEAN gas pipeline project because of its enormous gas reserves. ASEAN members have previously said that a regional natural gas pipeline, as well as an electricity grid, is the most efficient way for ASEAN countries to prevent a future energy crisis. Indonesia has already developed several pipelines - from West Natuna to Singapore, West Natuna to Malaysia, and from South Sumatra to Singapore. It is also studying a possible pipeline from West Natuna to Thailand.

ASEAN members will develop regulations and frameworks for the cross-border supply, transportation and distribution of natural gas throughout the region. This will be supervised by a future ASEAN Gas Consultative Council. The key reason behind the gas grid is the need to reduce oil consumption and to provide backup energy sources for

ASEAN members. ASEAN members hope to complete the gas grid by 2020. However, recent press reports indicate that delays in developing Natuna Block D Alpha have delayed the project.

Integrated Transmission System

The South Sumatra pipeline is part of state gas company PGN's plan for an integrated gas transmission pipeline system, known as the Integrated Gas Transportation System (IGTS). The IGTS will eventually link the islands of Sumatra, Java, and Kalimantan via a 4,200-kilometer integrated gas pipeline. Reputed to be Southeast Asia's longest, the pipeline is being funded by the World Bank, ADB, other institutions, as well as PGN's own internal funding. PGN's network will flow 2.2 bcfd of natural gas after its scheduled completion in 2010.

Project One - Grissik-Duri Pipeline

Phase One became operational in 1998. The 544-kilometer Grissik/Duri gas transmission pipeline transports 310 mmcf/d of natural gas from the Grissik gas plant in ConocoPhillips Indonesia's Corridor PSC in South Sumatra. The project will supply Caltex's Duri Steam Flood Project in Central Sumatra for 15 years. ConocoPhillips is the producer, Caltex is the buyer, and PGN is the pipeline network owner.

The Grissik/Duri pipeline project is the first part of an 850-kilometer gas transmission pipeline to link South Sumatra to Singapore. Phase Two, which covers a 530-kilometer leg from Grissik to Singapore by way of Batam Island, was completed in August 2003. Both the Grissik/Duri pipeline and the Grissik/Singapore pipeline have been included in the TransgasIndo pipeline

consortium, jointly owned and operated by PGN and a joint venture among ConocoPhillips, Petronas, Talisman, and Singapore Petroleum.

Project Two: South Sumatra–West Java Pipeline

This 1,100-kilometer pipeline project provides gas from ConocoPhillips and Pertamina fields in Sumatra to West Java power plants and industrial users. A combination of JBIC loans and proceeds from a PGN bond and IPO offerings funded the construction, which was completed in 2007.

Phase I of the project involved construction of a 450 kilometers pipeline from Pagardewa, South Sumatra to Cilegon and Serpong, West Java. Phase I provides 250 mmcf/d of gas from Pertamina's Pagardewa gas field and ConocoPhillips' Grissik field to the Muara Tawar, Tanjung Priok and Muara Karang gas-fired power plants in Jakarta.

Phase II connects Grissik to Pagardewa via a 270 km pipeline, a parallel line from Pagardewa to Labuhan Maringgai and a 190 km pipeline from Labuhan Maringgai to Muara Bekasi, and Rawamaju in West Java. Phase II can provide up to 600 mmcf/d. PGN completed the procurement tender for the project in 2005 and finished construction two months ahead of schedule in October 2007. This pipeline supplies natural gas from Pertamina's gas fields in Prabumulih to West Java industrial users.

In September 2007, the downstream regulator announced a tender worth \$269 million for a 220 km extension of the pipeline from Muara Bekas to Cirebon. The government closed bidding for the

project in February 2008 and aims to have gas flowing by 2010.

Project Three: East Kalimantan-Central Java

The most ambitious of the five projects, the 1,200-kilometer East Kalimantan-Java pipeline would transport up to 1.1 bcf/d of gas through a combined offshore and onshore pipeline stretching from Kuala Badak, East Kalimantan to Semarang, Central Java. PGN would partially fund the project from a bond and IPO offering. At an estimated cost of \$1.2 billion, PGN will need substantial outside financing. PGN completed the feasibility study of the project and announced the tender in December 2005. PT Bakrie Brothers won the tender in July 2006 and has been seeking financing and gas commitments since that time. Consequently, PGN did not meet its original target to begin project construction in 2007. It is doubtful that they will meet their other goal of flowing first gas in 2010, according to industry analysts and media reports.

Project Four: East/West Java Pipeline

This proposed project will involve construction of a 730 kilometers pipeline stretching from Gresik (East Java) to Cirebon and Muara Bekasi (West Java) along with a 300-kilometer East and Central Java distribution link. The pipeline will have the capacity to transport about 700 mmcf/d of natural gas and cost an estimated \$540 million. Currently PGN plans for project construction to start in 2008 with completion in 2010.

Project Five: Duri – Dumai – Medan Pipeline

An extension of the Grissik-Duri project, the 521-kilometer pipeline will transport gas from Duri, Riau to Medan, North

Sumatra. The project will be the northern extension of an integrated Sumatra transmission network and supply gas to Asahan Power. PGN, Kondur Petroleum and Asahan Power signed an MOU in October 2004 for the sale of 80-140 mmcf/d gas through the pipeline. PGN plans to finance the estimated \$574 million project via internal and external finance lending. In March 2008, PGN pushed back the start date for construction to sometime in 2009.